State of California

Department of Water Resources

Revision to 2005 Revenue Requirement Determination

For the Period

January 1, 2005, Through December 31, 2005

Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

February 28, 2005

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PROPOSED REVISIONS TO THE DEPARTMENT'S NOVEMBER 4, 2004 DETERMINATION

On November 4, 2004, the State of California Department of Water Resources (the "Department") published its Determination of Revenue Requirements for the period of January 1, 2005 through and including December 31, 2005 (the "November 4, 2004 Determination") and submitted it to the Commission. The November 4, 2004 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, AB1X, the Regulations, Bond Indenture requirements and the Rate Agreement. Unless otherwise defined herein, capitalized terms have the meanings given to them in the November 4, 2004 Determination.

The Department has reviewed certain matters relating to its 2005 revenue requirement, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of December 31, 2004; the El Paso Energy Settlement Agreement; the Williams Energy Marketing & Trading Settlement Agreement; and developments in natural gas markets. The Department proposes to revise its November 4, 2004 Determination under Section 516 of the Regulations to address the following matters:

- Updated actual Electric Power Fund operating results through December 31, 2004;
- El Paso Energy Settlement Agreement;
- Williams Energy Marketing & Trading Settlement Agreement; and
- Natural Gas Price Forecasts and Related Assumptions.

In addition, the Department has revised the methodology employed to model the Bond Charge Payment Account required balance to take into account the difference between the actual historical variable rate component of total debt service and the variable interest rate projection.

These proposed revisions would result in a total reduction in the Department's 2005 Revenue Requirement (the "Revised 2005 Determination") of $166 million relative to the November 4, 2004 Determination (the cash basis revenue requirement presented in the November 4, 2004 Determination totaled $4.824 billion). This reduction is comprised of two components: a $91 million decrease in the Department's Power Charge Revenue Requirements; and a $75 million decrease in the Department's Bond Charge Revenue Requirements.

The $91 million Power Charge Revenue Requirement reduction results primarily from the net effects of a $125 million reduction in projected power costs (net of a $50 million reduction in projected extraordinary receipts from settlement agreements), a $56 million reduction in projected gas collateral costs, and a $37 million reduction in projected revenues from surplus energy sales. The reduction in projected power costs largely results from a decreased fuel price forecast for the 2005 Revenue Requirement Period. As noted below in table D-10, the Department's natural gas price forecast has decreased nearly $1.00/MMBtu relative to the fuel price forecast underlying the November 4, 2004

Determination. The reduction in the Department's fuel price forecast, as well as existing unallocated hedging account balances, also contributed to the projected reduction in gas collateral costs for the Revised 2005 Determination.

The reduction in projected extraordinary receipts results from a methodological change in tracking fuel cost savings related to the Williams Natural Gas Purchase Contract. In the November 4, 2004 Determination, it was assumed that all fuel supplied through the Williams Natural Gas Purchase Contract would be sold and resultant projected revenues would be credited to the Department. From an operational perspective, this is not accurate. In the proposed revision to the 2005 Revenue Requirement, all fuel supplied from the Williams Natural Gas Purchase Contract is assumed to be used for contract dispatch, effectively reducing the total cost of power based on the lower-than-market fuel cost associated with the Williams fuel contract. Surplus energy sales revenues have also decreased relative to the November 4, 2004 Determination based on the aggregate effects of reduced surplus sales volume and price projections. Tables B-3 and B-4 (below) summarize these changes between the November 4, 2004 Determination and the Revised 2005 Determination.

The proposed revisions address only those changes under the aforementioned subjects. All other previous assumptions underlying the November 4, 2004 Determination remain unchanged. Based on the timing of these revisions, some dates and quantitative references have also been updated to reflect actual operating results through December 31, 2004 (the November 4, 2004 Determination reflected actual operating results through September 30, 2004). These changes, while important to consider, have not significantly affected the Department's 2005 Revenue Requirements.

A redlined draft of the November 4, 2004 Determination has been prepared, reflecting all changes (including relevant updates to Section I – Annotated Reference Index of Materials Upon which the Department Relied to Make Determinations) not included herein, and is part of the administrative record supporting this proposed revision to the November 4, 2004 Determination. Appropriate section headings, as included in the November 4, 2004 Determination, are also included herein to facilitate document comparison and review.

A. THE DETERMINATION

DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby proposes to determine, on the basis of the materials presented and referred to by this Revised 2005 Determination (including the materials referred to in Section I), that its cash basis revenue requirement for 2005 is $4.658 billion, consisting of $3.808 billion in power charge revenues and $0.850 billion in bond charge revenues.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with projected Department Costs ("Power Charge Accounts") for 2005. These figures are compared to those reflected in the Department's Supplemental Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004, published April 16, 2004 (the "2004 Supplemental Determination").

A summary and comparison of the Department's revenue requirements and accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S REVISED 2005 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2004[1]
($ Millions)

Line	Description	2005[2]	2004[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,128	1,031	98
3	Priority Contract Account	63	-	63
4	Operating Reserve Account	595	630	(35)
5	**Total Beginning Balance in Power Charge Accounts**	**1,786**	**1,660**	**125**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,808	4,272	(464)
8	Extraordinary Receipts[5]	11	52	(41)
9	Other Revenue[6]	236	273	(37)
10	Interest Earnings on Fund Balances	26	32	(6)
11	**Total Power Charge Accounts Operating Revenues**	**4,081**	**4,628**	**(547)**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	59	(14)
14	Total Power Costs	4,425	4,860	(434)
15	Gas Collateral Costs	52	37	15
16	**Total Power Charge Accounts Operating Expenses**	**4,522**	**4,956**	**(434)**
17	Net Operating Revenues	(441)	(327)	(114)
18	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	7	(7)
19	Total Net Revenues	(441)	(321)	(120)
20	**Ending Aggregate Balance in Power Charge Accounts**	**1,345**	**1,340**	**5**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	275	296	(21)
Operating Reserve Account: covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	553	595	(41)
Total Operating Reserves:	828	891	(63)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2004 Supplemental Determination.
[4]CRS Power Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Includes funds distributed to the Department as specified in settlement agreements with various energy suppliers; details related to individual settlement receipts are further discussed in Section D.
[6]Includes revenues received by the Department from surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S REVISED 2005 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2004[1]
($ Millions)

Line	Description	2005[2]	2004[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	199	129	70
3	Bond Charge Payment Account	572	429	143
4	Debt Service Reserve Account	927	927	0
5	**Total Beginning Balance in Bond Charge Accounts**	**1,698**	**1,485**	**213**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	850	891	(41)
8	Interest Earnings on Fund Balances	47	26	21
9	**Total Bond Charge Accounts Revenues**	**897**	**918**	**(21)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	725	196
12	**Total Bond Charge Accounts Expenses**	**922**	**725**	**196**
13	Net Bond Charge Revenues	(25)	192	(217)
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(25)	192	(217)
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,673**	**1,677**	**(4)**

Target Minimum Bond Charge Account Balances	**Target (Millions of Dollars)**		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	76 - 78	75 - 78	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	237 - 834	300 - 702	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2004 Supplemental Determination.
[4]CRS Bond Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.

B. BACKGROUND

Table B-3 summarizes the changes between the November 4, 2004 Determination and this Revised 2005 Determination for the Power Charge revenue requirement and Power Charge Accounts. Table B-4 summarizes the changes between the November 4, 2004 Determination and this Revised 2005 Determination for the Bond Charge revenue requirements and Bond Charge Accounts.

TABLE B-3
SUMMARY OF THE DEPARTMENTS REVISED 2005 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS COMPARED TO THE NOVEMBER 4, 2004 DETERMINATION[1]

Line	Description	2005[2]	2005[3] (Nov. 4, 2004)	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,128	1,167	(39)
3	Priority Contract Account	63	-	63
4	Operating Reserve Account	595	595	-
5	**Total Beginning Balance in Power Charge Accounts**	**1,786**	**1,762**	**24**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,808	3,899	(91)
8	Extraordinary Receipts[5]	11	61	(50)
9	Other Revenue[6]	236	273	(37)
10	Interest Earnings on Fund Balances	26	26	1
11	**Total Power Charge Accounts Operating Revenues**	**4,081**	**4,258**	**(177)**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	45	-
14	Total Power Costs	4,425	4,550	(125)
15	Gas Collateral Costs	52	107	(56)
16	**Total Power Charge Accounts Operating Expenses**	**4,522**	**4,703**	**(181)**
17	Net Operating Revenues	(441)	(444)	3
18	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	-	-
19	Total Net Revenues	(441)	(444)	3
20	**Ending Aggregate Balance in Power Charge Accounts**	**1,345**	**1,317**	**27**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	275	282	(7)
Operating Reserve Account: covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	553	564	(11)
Total Operating Reserves:	828	846	(19)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the November 4, 2004 Determination.
[4]CRS Power Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Includes funds distributed to the Department as specified in settlement agreements with various energy suppliers; details related to individual settlement receipts are further discussed in Section D.
[6]Includes revenues received by the Department from surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.

TABLE B-4
SUMMARY OF THE DEPARTMENTS REVISED 2005 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS COMPARED TO THE NOVEMBER 4, 2004 DETERMINATION[1]

Line	Description	2005[2]	2005[3] (Nov. 4, 2004)	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	199	92	107
3	Bond Charge Payment Account	572	681	(110)
4	Debt Service Reserve Account	927	927	0
5	**Total Beginning Balance in Bond Charge Accounts**	**1,698**	**1,700**	**(3)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	850	925	(75)
8	Interest Earnings on Fund Balances	47	47	(0)
9	**Total Bond Charge Accounts Revenues**	**897**	**972**	**(76)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	922	-
12	**Total Bond Charge Accounts Expenses**	**922**	**922**	**-**
13	Net Bond Charge Revenues	(25)	51	(76)
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(25)	51	(76)
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,673**	**1,751**	**(78)**

Target Minimum Bond Charge Account Balances	Target (Millions of Dollars)		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	76 - 78	76 - 78	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	237 - 834	351 - 947	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the November 4, 2004 Determination.
[4]CRS Bond Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.

C. THE DEPARTMENT'S REVISED DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2005 THROUGH DECEMBER 31, 2005

Table C-1 provides a revised quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2005 Revenue Requirement Period. Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2005 Revenue Requirement Period.

TABLE C-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: REVISED RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2005 - Q1	2005 - Q2	2005 - Q3	2005 - Q4	Total
1	*Power Charge Accounts Expenses*					-
2	Power Costs	1,150	909	1,222	1,144	4,425
3	Administrative and General Expenses	11	11	11	11	45
4	Gas Collateral Costs	-	6	25	21	52
5	Net Changes to Power Charge Account Balances	(13)	(54)	(253)	(122)	(441)
6	**Total Power Charge Accounts Expenses**	**1,148**	**872**	**1,005**	**1,055**	**4,081**
7	*Power Charge Accounts Revenues*					
8	Extraordinary Receipts	5	-	5	-	11
9	Other Power Sales Revenues	69	45	57	66	236
10	Interest Earnings on Power Charge Account Balances	7	7	7	6	26
11	Total Power Charge Revenue Requirement[1]	1,068	821	937	983	3,808
12	**Total Power Charge Accounts Revenues**	**1,148**	**872**	**1,005**	**1,055**	**4,081**

[1]Represents the Department's Retail Revenue Requirement, except to the extent funded by surcharge revenues.

TABLE C-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: REVISED RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2005 - Q1	2005 - Q2	2005 - Q3	2005 - Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	35	623	36	227	922
3	Net Changes to Bond Charge Account Balances	175	(407)	195	12	(25)
4	**Total Bond Charge Accounts Expenses**	**211**	**217**	**231**	**239**	**897**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	4	20	4	19	47
7	Retail Customer Bond Charge Revenue Requirement	207	197	227	220	850
8	**Total Bond Charge Accounts Revenues**	**211**	**217**	**231**	**239**	**897**

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROPOSED REVISIONS OF POWER CHARGE REVENUE REQUIREMENTS FOR THE 2005 REVENUE REQUIREMENT PERIOD

EL PASO ENERGY SETTLEMENT AGREEMENT

On June 24, 2003, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with El Paso Energy that resulted in the Department's receipt of nearly $161 million on June 28, 2004. The receipt of $161 million is a combination of several components specified within the Master Settlement Agreement, which include nearly $109 million related to proceeds from El Paso Energy's requisite corporate stock sale, nearly $50 million in monthly contract price reductions and associated interest for the period beginning July 2003 through June 2004, and $2.1 million to reimburse the Department for attorneys' fees and costs related to this settlement. Amendment #1 to the El Paso power purchase agreement also provides for price reductions from May 2004 through the contract's expiration in December 2005, yielding an additional $75 million in contract cost reductions.

In addition, on December 24, 2004 the Department received a cash payment of $2.7 million from El Paso Energy ($2.7 million less than expected, due to the addition of two parties to the Master Settlement Agreement). This payment was the first in a series of semiannual cash payments that were scheduled to begin in July 2004 as deferred consideration from El Paso Energy. The $2.7 million settlement receipt is reflected in the beginning account balances for the 2005 Revenue Requirement Period.

Semiannual cash payments are to be made in the amount of $5.4 million and will be paid by El Paso Energy to the Department each January and July for the next 20 years (39 payments of $5.4 million, totaling approximately $209 million over 20 years), ending with a final payment in January of 2024. The payment scheduled for receipt in January 2005 remains in escrow, pending the resolution of additional settlement-specific details. For the purposes of this Determination, the Department is projecting receipt of the January 2005 scheduled payment during the month of March 2005.

Due to the inclusion of two additional parties in this Settlement Agreement, projected semiannual payments were slightly decreased in relation to amounts noted in the November 4, 2004 Determination ($5.5 million/semiannual – November 4, 2004 Determination).

WILLIAMS ENERGY MARKETING & TRADING SETTLEMENT AGREEMENT

On November 11, 2002, the State of California, Office of the Attorney General, executed a Settlement Agreement with Williams Energy Marketing and Trading ("Williams") that resulted in the renegotiation of the original Power Purchase Agreements between the Department and Williams as well as the development of a Natural Gas Purchase Contract between the Department and Williams (natural gas deliveries began on January 1, 2004). During the 2005 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in savings of approximately $35.3 million, based on the difference between the contract fuel price of $3.85 and the Department's projected average annual fuel price of $5.82.

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this Revised 2005 Determination is an update of the October 2004 gas price forecast used in the November 4, 2004 Determination. This forecast reflects a decrease to the 2005 price forecast when compared to the October 2004 price forecast supporting the November 4, 2004 Determination.

A comparison of the year-over-year Henry Hub prices forecast in the November 4, 2004 Determination and the update used in this Revised 2005 Determination is shown in Table D-10.

TABLE D-10
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2005	**2006**	**2007**
February 2005 Gas Price Forecast	$6.38	$5.75	$5.54
October 2004 Gas Price Forecast	$7.35	$6.22	$5.77
Difference	$(0.97)	$(0.47)	$(0.23)

The gas price forecast was prepared by using a proprietary econometric Long-Term Price Model, the same model used in all prior revenue requirement determinations. This model forecasts prices for Henry Hub and then uses regression analyses between Henry Hub and several other pricing points, including PG&E Citygate and the Southern California Border, to arrive at prices for these locations. The February 2005 forecast updates the Henry Hub base forecast using actual wellhead gas prices through December 2004, and updated data for well completions and weather-adjusted storage variables. To forecast monthly prices at Henry Hub for 2005, a 10-day average of settlement prices for NYMEX contracts for March through December 2005 were combined with published historical monthly index prices for January and February 2005, with the resultant annual average price for 2005 price distributed across the 12 months using historical spread factors. The period for the 10-day average NYMEX prices included daily settlements up to and including February 17, 2005. Once the base forecast price was determined at Henry Hub, specific delivery point prices were projected using price regression analysis to the various respective delivery point locations utilized by the model. Monthly prices were then determined by using historical spread factors.

Table D-11 illustrates the February 2005 price forecast at two key pricing hub locations: PG&E Citygate and Southern California Border.

TABLE D-11
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		**PG&E Citygate**	
	2005	**2006**	**2005**	**2006**
January	$6.45	$5.88	$6.71	$6.11
February	$5.51	$5.02	$5.73	$5.22
March	$5.32	$4.85	$5.53	$5.04
April	$5.62	$5.12	$5.84	$5.32
May	$5.94	$5.42	$6.18	$5.63
June	$6.01	$5.47	$6.24	$5.69
July	$5.87	$5.35	$6.10	$5.56
August	$5.46	$4.97	$5.67	$5.17
September	$5.62	$5.12	$5.84	$5.32
October	$5.77	$5.26	$6.00	$5.46
November	$6.18	$5.64	$6.43	$5.86
December	$6.11	$5.57	$6.35	$5.79
Annual Average	**$5.82**	**$5.31**	**$6.05**	**$5.51**

For the purposes of this Revised 2005 Determination, downstream pipeline and local distribution tariff charges from forecast pricing hub locations to individual plant locations throughout the WECC were calculated and then utilized to arrive at a contract specific delivered fuel price forecast. In revenue requirement determinations prior to the November 4, 2004 Determination, gas prices were forecast to major gas price hub locations only, such as the Southern California Border, the PG&E Citygate and others such as the Rockies and AECO "C" in Alberta. This method may have resulted in an understatement of total delivered gas costs.

The purpose of including transportation costs downstream of the hub locations is to accurately align forecasted fuel costs with actual fuel costs at the plant level. The current price forecast does not incorporate transportation rates in the PG&E service territory as a result of the Gas Accord III decision in December 2004, which reduced backbone rates from Malin and increased rates for transport from Topock.

GAS COLLATERAL COSTS

For the 2005 Revenue Requirement Period, the Department has identified, as a separate line item, cash collateral provided in connection with gas purchases. These funds are to enable the hedging decisions of the IOUs in connection with the operation of the Department's power contracts. The Department analyzed the NYMEX margin requirements to secure futures on the highest seven months of fuels requirements. Margin requirements of the NYMEX exchange are listed by the exchange. The margins are exchange requirements based upon a fixed price per futures contract and also, separately, upon fixed prices per basis contract. In order to determine a total margin cost, anticipated fuel volumes from June through December 2005 were utilized. These anticipated fuel volumes are determined through the use of the production simulation analysis supporting this Revised 2005 Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from June through December 2005 would be $83 million. This amount is 22% lower than the 2005 collateral requirement of $107 million included in the November 4, 2004 Determination. The decrease in margin requirements is due primarily as a result of decreased NYMEX contract margin costs, which reflect decreased natural gas prices and volatility in the natural gas market, and the exclusion of gas volumes provided by Williams via a negotiated fixed contract price.

While the Department's collateral requirement for 2005 is determined to be $83 million, the hedging account held by the Department with A.G. Edwards contained $31 million that was not allocated to any investment or IOU sub-account as of December 31, 2004. The amount required for 2005 ($83 million), therefore, is decreased by the amount currently held in the account ($31 million), meaning that $52 million is required from this Determination.

The IOUs have supplied DWR with copies of data request responses sent to the CPUC related to the gas collateral costs identified in the November 4, 2004 Determination. These data request responses have been included in the administrative record supporting this proposed revised determination but have been designated as confidential. The IOUs have also supplied recent Gas Supply Plans, which were reviewed in the development of the Department's collateral costs. These materials have also been designated as confidential. Since the November 4, 2004 Determination was submitted, short-term gas prices have fallen significantly and the Department has adjusted gas prices accordingly, resulting in the use of gas prices that are even lower than those suggested by at least one IOU in its data request response to the CPUC.

As noted above, the Department uses the anticipated gas requirements for a seven-month period based on the production simulation analysis that supports this Determination. Another methodology may be to use the ratable rate volume provided in the IOUs' Gas Supply Plans for the DWR Long-Term Contracts. Ratable rate volumes are determined in order to identify maximum forward physical purchases of gas to meet requirements for the Long-Term Contracts. Because the gas collateral cost is intended to reflect the potential cost of placing financial hedges for the gas supply required for the Long-Term Contracts, the Department does not believe that the use of ratable rate volumes identified for forward physical purchases is appropriate. Financial hedges can be placed on all volumes at any time, and maintaining an adequate collateral balance allows the Department and the IOUs to maintain the flexibility necessary to hedge against increasing gas costs.

In the confidential response to the CPUC's data request, another IOU suggested that it intended to request that financial hedges be placed on a significantly smaller amount of gas requirements than the full hedge assumption made by DWR in the November 4, 2004 Determination and that much of that hedging would be performed through the use of lessexpensive option hedges. The Department agrees that all of the IOUs should have this flexibility, but DWR believes that providing adequate financial backing for such flexibility requires collateral in the amount determined by the Department in this Revised 2005 Determination.

The Department has reviewed and corrected specific errors identified by another IOU in its response to the CPUC's data request. These errors related to the determination of an initial margin requirement for a specific DWR contract and the size, and subsequent number, of the basis contracts used to calculate the cost of collateral. The errors, while minor have been corrected in this Revised 2005 Determination.

Finally, in response to the CPUC's data request, one of the IOUs' suggested a different method of determining the cost of collateral: The Department should finance the collateral requirement rather than hold the full amount of money that is collected from ratepayers. This method, or so the IOU contends, would decrease the cost to ratepayers from the full collateral cost to the cost of carrying the collateral cost, either through interest on borrowing or through the cost of a letter of credit. The Department is currently considering this alternative and welcomes additional suggested methods to decrease costs to ratepayers. It is worth noting, however, that ultimately, when the Department no longer needs to hold collateral for gas hedging, the amount held in the hedging account will be returned to ratepayers. As such, the actual cost to ratepayers of the method currently employed by the Department is the cost of carrying the collateral requirement, not the full collateral requirement. The "financing" of this collateral is simply done internally, rather than externally through a financial institution. Also, in either method, hedging costs will be incurred. To the extent that those costs were covered by funds that were externally financed as a collateral requirement, additional financing would need to be undertaken to replenish the collateral requirement.